Case Study of a Multiple Sand Waterflood, Hewitt Unit, OK

David B. Ruble, SPE, Exxon Co. U.S.A.

Summary

Twenty-two sands in the Hewitt field have been flooded simultaneously by Exxon Co. U.S.A.'s Hewitt Unit, and a case history of the operations is detailed in this paper. A multiple sand waterflood project requires special optimization methods to improve oil recovery. Injection and production surveillance programs and optimization methods used are highlighted. These include injection wellbore design, injection distribution, production stimulation, polymer augmented injection, and infill drilling. Successful application of these techniques has increased ultimate recovery from this waterflood operation.

Introduction

Hewitt Unit is located 20 miles (32.2 km) west of Ardmore in south central Oklahoma and covers approximately 2,600 acres (10.52 km^2) (Fig. 1). The Unit became effective March 1, 1968, for the purpose of conducting a waterflood in 22 separate Pennsylvanian-age sands.

Currently the unit has 147 active producing wells and 142 active injectors on a 20-acre (80 937-m^2) five-spot pattern with each productive sand open in the wellbore. All zones are commingled in the producers, and a total of 419 individual injection strings provide waterflood support. The unitized production peaked at 14,000 BOPD (2226 m^3/d oil) in Jan. 1973 and has declined to a current level of 4,500 BOPD (715 m^3/d oil). Injection rates were as high as 200,000 BWPD (31 797 m^3/d water) but have been reduced to a current level of 160,000 BWPD (25 438 m^3/d water).

Primary Production

Hewitt, one of the oldest fields in Oklahoma, was discovered in 1919. Development was rapid during the 1920's, with primary production peaking at 27,000 BOPD (4293 m^3/d oil) in 1921. The spacing was erratic, with approximately 1,000 wells drilled for an average of 2.5 acres (10 117 m^2) per well.

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In the early days completion was accomplished by drilling through the first major producing zone and running slotted production casing across the producing interval. Cemented casing was the exception rather than the rule. After production had declined, the well was deepened through the next major interval and smaller slotted casing was run to total depth. This procedure was repeated in many instances. Initially all casing was hung from the surface and, later, upper portions of the multistrings were salvaged, leaving uncemented slotted liners.

Hewitt was a prolific field producing 98.5 MMbbl (15.6×10^6 m^3) before unitization, or an average of 37,800 bbl/acre (1.485 m^3/m^2). After 49 years of life, operations had declined to the stripper stage and several hundred wells had been shut down or abandoned. Production before unitization was 2,700 BOPD (429 m^3/d oil) from 600 active wells, or 4.5 BOPD (0.7 m^3/d oil) per well. The average decline in production was 4% per year, and some leases had a projected life beyond the year 2000.

Recovery was principally by solution-gas drive augmented by gravity drainage on downstructure leases. Water/oil contacts were to the south, southeast, and west of the field, but no active water drive was present. Gas caps were present initially in some sands, but no effective gas drive was realized because the gas caps were dissipated rapidly during early development.

Geology

The geologic section and nomenclature adopted in identifying individual sands is shown on a type log (Fig. 2). The section is a sand/shale sequence of the Hoxbar and Deese formation of Pennsylvanian age. Gross interval between the top and lowermost sands is 1,500 to 1,600 ft (457 to 488 m). The average depth of the sands ranges from 1,200 to 2,900 ft (365 to 844 m) subsurface. The pay interval is divided into five major zones, the first Hewitt through the fifth. The sands within a zone are termed A, B, etc., with the exception of the Stearns and Chubbee at the top. Four sands comprise 73% of the

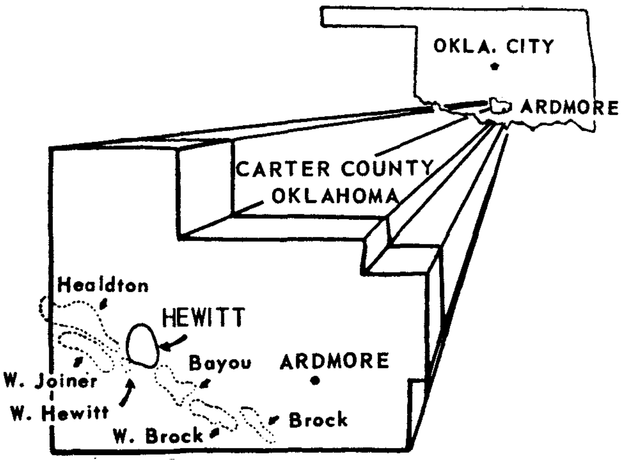

Fig. 1—Location map, Hewitt Unit.

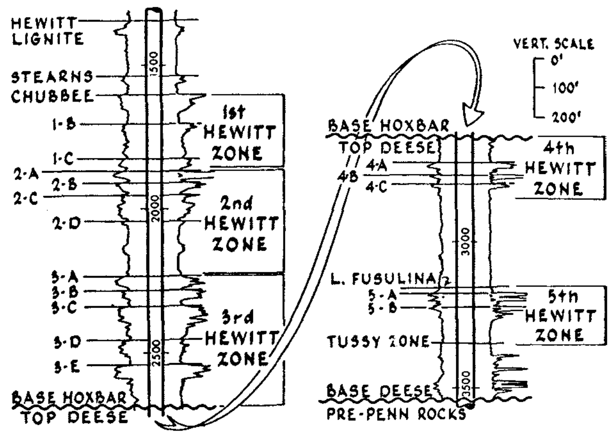

Fig. 2—Composite type log, Hewitt field.

total acre feet: the Chubbee, 2C, 3C, and 3E.

The Hewitt structure contoured on the Chubbee is shown in Fig. 3. It is a northwest-to-southeast trending anticline with a 12° dip to the west and south. The productive limits of the field are bounded by water/oil contacts to the west, south, and southeast, by a major fault to the north, and by steep dip and faulting to the east. Fig. 4 shows a plat of the unit with the water/oil contacts of the major sands. Most of the 22 sands contain water/oil contacts, and they occur at about the same subsea elevation. Moving from low to high on the structure, the number of sands within the oil column increases, and inside Zone 3E productive limit a maximum net sand thickness of up to 225 ft (68.6 m) occurs.

Waterflood Development

Exxon began evaluating Hewitt as a waterflood prospect in the mid-1950's. As the major acreage owner, Exxon did most of the geological and engineering work during negotiations with 47 other operators. A summary of the unit's reservoir data is shown in Table 1.

The waterflood was developed in three stages (Fig. 5). Initial flooding began in 1969 in the southern and southwest portions. This portion of the field was favored because of the structurally lower position of the sands and the anticipated higher oil saturations caused by gravity drainage. In addition, the south end was closer to a source water supply. By the end of 1970, the north half of Section 22, all of Section 9, and the top of Section 16 were under flood. The final expansion occurred in 1971, when 600 acres (2 428 124 m^2) were added in Sections 10 and 15, and the balance of Section 16.

The flood pattern is a 20-acre (80 937-m^2) five-spot with some irregularities. The unit drilled 53 of the 147 active producers and 86 of the 142 active injectors, with the balance being older primary wells brought into the unit. These old wells were utilized as much as possible to minimize costs. Many new wells and major workovers of old wells were necessary to provide cemented casing strings for injection wells. Flood development included the plugging of 680 wells. Plugging costs total \$4,500,000 or approximately 25% of the flood development cost. The total waterflood investment of \$18,500,000 was paid out in 1974.

Ninety-two of the 147 producing wells are equipped with electric submersible pumps and the other 55 are conventional rod pumps. Production is monitored through a central tank battery. Initially source water was supplied by five wells completed in a 1,200-ft (366-m) saltwater sand 8 miles (12.9 km) south of the unit. Cur-

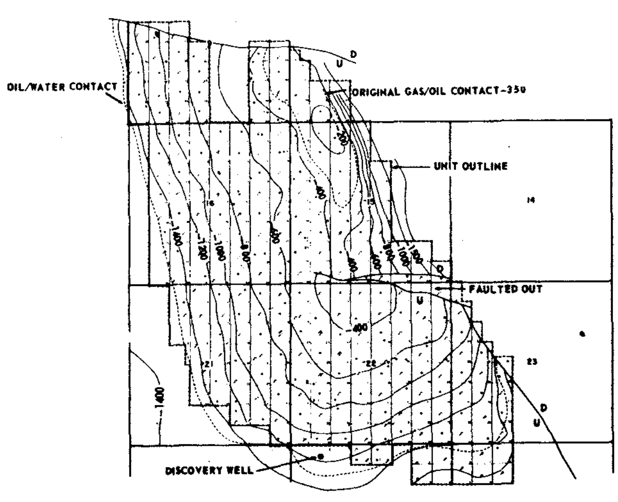

Fig. 3—Hewitt Unit, Chubbee structure.

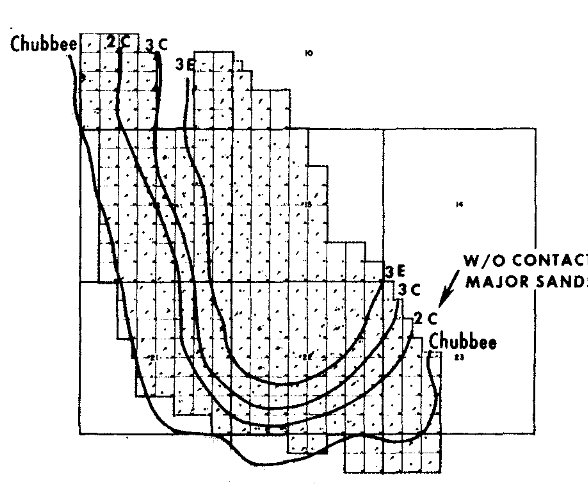

Fig. 4—Water/oil contacts of the major sands.

TABLE 1—HEWITT UNIT RESERVOIR DATA

General	
Unit area, acre	2,610
Floodable net sand volume, acre-ft	284,700
Average composite thickness, ft (22 separate sand reservoirs)	109
OOIP, MMbbl	350.8
Rock Properties	
Permeability, md	184
Porosity, %	21.0
Connate water, %	23.0
Lorenz coefficient	0.49
Permeability variation	0.726
Fluid Properties	
Mobility ratio	4.0
Original reservoir pressure, psig	905
Reservoir temperature, °F	96
Original FVF, RB/STB	1.13
Flood start FVF, RB/STB	1.02
Oil stock-tank gravity, °API	35
Oil viscosity, cp	8.7
Original dissolved GOR, cu ft/STB	253
Primary recovery mechanism	solution-gas drive gravity drainage

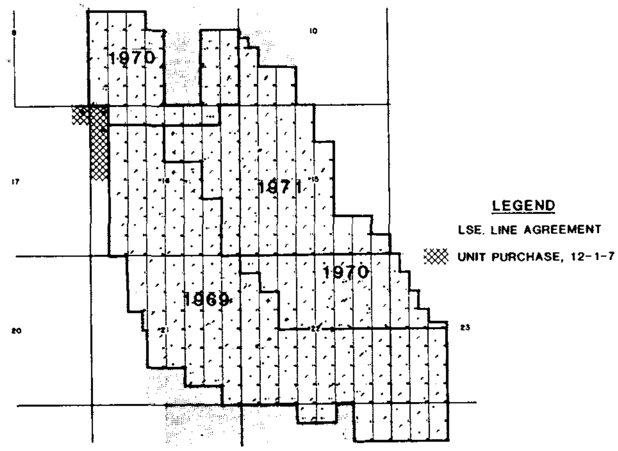

Fig. 5—Hewitt Unit flood development.

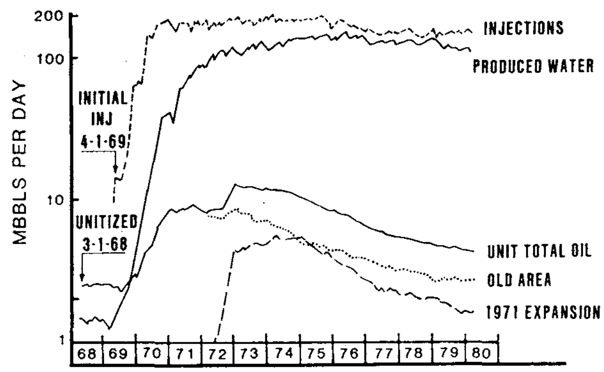

Fig. 6—Hewitt Unit operations.

rently only two of the wells are maintained for makeup requirements. Produced water is treated in coalescers and sand filters before reinjection. Source water has been commingled with produced water since 1975 without any adverse effects.

Operations

Unit operations, shown in Fig. 6, began with injection in April 1969, and approximately 6 months later oil response occurred. Production increased steadily during 1970, to 9,000 BOPD (1431 m^3/d oil), and then leveled off during the next 20 months at an average of 9,500 BOPD (1510 m^3/d oil) through Aug. 1972. Response from the 1971 expansion area combined with the remainder of the unit to peak production at 14,000 BOPD (2226 m^3/d oil) during Jan. 1973. The unit production declined at a constant rate of 24% per year from 1974 until 1977, when the decline began to shift to the current decline rate of 12% per year.

Water production rose rapidly along with early flood gains, and by 1972 exceeded 90,000 B/D (14 309 m^3/d) for a water cut of more than 90%. This high water-cut behavior was expected. Preunit engineering studies had predicted this type of behavior, caused primarily by permeability variation.

Injection rose rapidly during the early development to 190,000 B/D (30 208 m^3/d), which is essentially plant capacity. Input remained at that level through the third quarter of 1975. The drop in injection after 1975 to the current level of 160,000 B/D (25 438 m^3/d) was due to selective injection cutbacks discussed later under Flood Optimization.

Cumulative withdrawals since unitization to Jan. 1, 1980, total 34 MMbbl (5 405 568 m^3) of oil and 425 MMbbl (67.6×10^6 m^3) of water. A total of 648 MMbbl (103×10^6 m^3) of water has been injected, which equates to a 1.4 reservoir pore volume throughput.

Injection Well Design

Initial waterflood studies indicated a large permeability variation in the sands at the Hewitt field. This, along with the large number of sands proposed to waterflood, indicated the need for injection water control to flood the field efficiently.

Fig. 7 illustrates a triple completion used to segregate injection mechanically. Surface casing was cemented below freshwater sands, and three staggered lengths of 2⅞-in. (7.3-cm) casing then were run and cemented to the surface. The short string, or Completion A, was set through the first Hewitt sand, String B through the second sand, and String C included the third, fourth, and fifth sands. Each completion string was perforated to include at least one of the four major sands (Chubbee, 2C, 3C, and 3E). This method of injection well completion enabled simultaneous flooding of most of the reserves. State regulatory approval was received to inject down cemented casing.

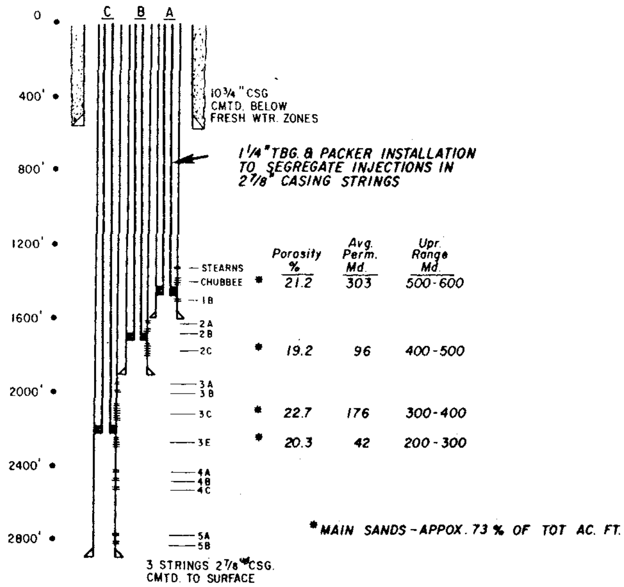

Fig. 7—Hewitt injection well, triple completion.

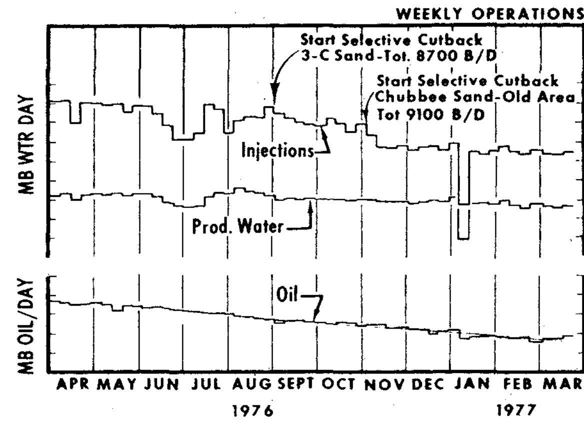

Fig. 8—Hewitt Unit selective injection cutbacks.

Injection Surveys

In a multiple sand waterflood, regularly scheduled injection profiles give information necessary to achieve control of water distribution and improve recovery efficiency. An average of 200 radioactive tracer profiles are run annually at Hewitt. Water injection is allocated to individual sands on the basis of these profiles. From the tracer surveys, injection allocations are set for each completion string. Profiles also identify thief zones, stimulation candidates, tubing and casing leaks, and channeling between zones.

Tubing and Packer Installations

When an imbalance of injection volumes is indicated between zones by well tracer profiles, tubing and packer installations can be used to improve distribution. As shown in Fig. 7, 1¼-in. (3.175-cm) tubing and packers are installed in the 2⅞-in. (7.3-cm) casing to allow injection down the tubing and tubing-casing annulus. This method is applicable only when there is sufficient pressure to inject water into the lower permeability zone. Currently there are 132 tubing and packer installations. These installations have enabled the unit to increase the number of separate injection streams to allow timely flooding of the less permeable producing sands.

Early profiling in the 1971 expansion area indicated the need for improved distribution. Of the 51 tubing and packer installations in this area, 41, or 80%, were completed by Jan. 1, 1973, before and during early flood response. Table 2 summarizes the flood results and 1971 expansion area. As shown, the 1971 area projected recovery of 174 bbl/acre-ft (22 427 $m^3/km^2 \cdot m$) is expected to exceed the old area by 19 bbl/acre-ft (2 449 $m^3/km^2 \cdot m$). The comparison of flood efficiency is of equal significance. The 1971 area has produced 1 bbl (0.16 m^3) of oil per 13.8 bbl (2.2 m^3) of injected water, compared with the old area's 1 bbl (0.16 m^3) of oil produced per 22 bbl (3.5 m^3) of water injected. This difference indicates a more efficient flood in the 1971 expansion area. We credit a major part of the increased flood efficiency in the expansion area to the early installation of the tubing and packer strings.

Waterflood Performance Predictions

Utilizing the injection profiles, an accurate account of injection into each sand is recorded to aid in predicting areas of low cumulative injection throughput and corresponding high oil saturations. A computer analysis run with the injection data models and predicts injection and production from individual producing sands. The producing wells have all the sands commingled in the wellbore. Because of the commingled status, oil recovery from any individual sand is virtually impossible to determine, and a prediction of oil recovery potential is made with injection data.

The computer analysis used at the Hewitt Unit to model waterflood performance is based on articles by Caudle.[1,2] The program provides a simplified model bridging the gap between three-dimensional reservoir simulators and rule-of-thumb prediction techniques. The program assumes steady-state flow, piston displacement, and noncommunicating layers. Within the limitations of the assumptions, the model accounts for areal sweep efficiency, vertical stratification, mobility ratio, initial gas saturation, and changing injectivity. The program output used at Hewitt is a comparison of cumulative injection to cumulative recovery and reserves. These reserve estimates are used to evaluate work programs on injection wells.

Selective Injection

Another optimization approach at the Unit has been the selective decrease or increase of injection into individual sands. The purpose of the injection changes is to allocate the injection water optimally into the sands with the highest oil saturation. These injection changes result in larger oil-cut production caused by less water cycling through depleted sands. The water injection cutbacks

TABLE 2—RECOVERY SUMMARY, OLD AREA vs. 1971 EXPANSION AREA (Jan. 1, 1980)

	Old Area	1971 Expansion	Unit Total
Floodable volume, acre-ft	190,664	94,036	284,700
Cumulative oil, MMbbl	22.7	10.8	33.5
bbl/acre-ft	119	115	118
Produced water, MMbbl	351.3	73.5	424.8
Water/oil ratio	15.5	6.8	12.7
Injections, MMbbl	499	149	648.0
bbl inj/bbl oil recovered	22	13.8	19.3
Ultimate unit oil recovery, MMbbl	29.6	16.4	46.0*
bbl/acre-ft	155	174	162*

*Does not include preunit production.

prevent a more depleted oil sand from flooding out a less depleted sand in the commingled producing well. Fluid levels are monitored on a regular basis in all producing wells in the field. The wells with a high fluid level are considered for the possibility of a decrease in offset injection. Conversely, low fluid level producers that potentially could benefit from injection increases are identified. The producing sand cumulative throughput of water and corresponding oil reserves are analyzed for the potential of injection changes.

During 1975 and 1976 several injection cutbacks were used to decrease injection into high water-cut sands. The first injection cutback, in Oct. 1975, amounted to 12,000 B/D (1908 m^3/d) in the Chubbee, and was followed by an increase in production of approximately 200 BOPD (31.8 m^3/d oil). The other two injection cutbacks were begun in Sept. and Nov. 1976 and totaled 17,800 B/D (2830 m^3/d). These injection decreases lowered injection costs while oil production remained unchanged. The decreases in injection did not alter the field decline but successfully lowered fluid levels. Fig. 8 shows production levels during 1976 following the injection cutback.

In the second half of 1977 the field decline began to change from a 24% per year rate to a 1980 decline rate of 12% per year. Selective injection increases were initiated in June 1977 and are credited as a principal reason for the gradual shift in field decline. A total increase of 12,250 BWPD (1948 m^3/d water) has been implemented to date. Fig. 9 shows an example of the effect of selective injection increases into less depleted sands during 1977-80. As shown, the injection increase in Section 15 resulted in increased oil production of as much as 350 BOPD (56 m^3/d oil).

Polymer Treatments

The Hewitt Unit has had three polymer-augmented injection projects. The projects have involved the injection of a high molecular weight, water-soluble polyacrylamide that becomes gelatinous when mixed with water. A cross-linking agent is injected, and this activates the polyacrylamide to form a viscous gel. The material will enter the most permeable section of the sand and build up yield strength to block and/or divert flow. The resulting pressure buildup diverts the injection water to less permeable flow channels that are less depleted and contain a higher oil saturation. This diversion of injection water improves the vertical sweep efficiency of the flood.

A map of three polymer project areas is shown in Fig. 10, and a summary of the three projects is presented in Table 3. Each of the projects injected polymer into the Chubbee sand, one of the four major unit sands. Treatments were sized to inject polymer at a 500-ppm concentration for 30 days. The objective was to increase injection wellhead pressure to as near plant injection pressure [1,080 psig (7445 kPa)] as possible while maintaining a constant rate of injection water. This increase in pressure indicates plugging of the most permeable

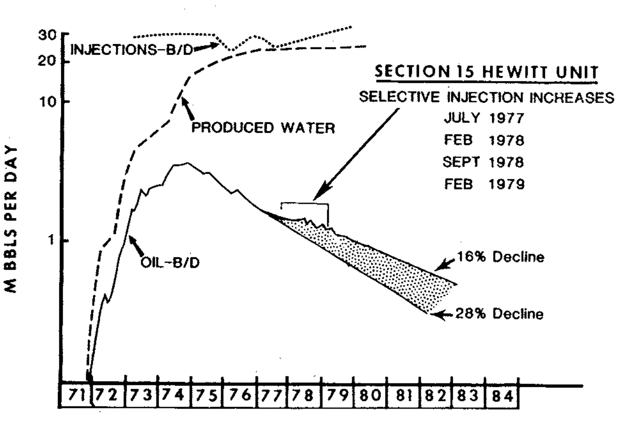

Fig. 9—Hewitt Unit selective injection increases.

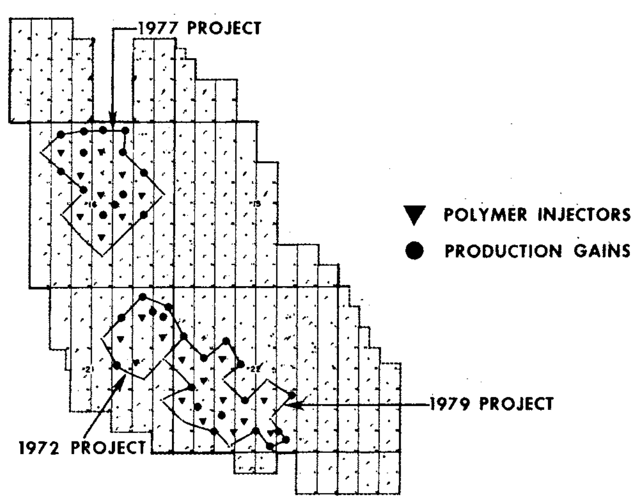

Fig. 10—Polymer project areas.

TABLE 3—HEWITT POLYMER PROJECTS

	1972	1977	1979
Injectors treated	4	9	10
Producers monitored	11	21	23
Number of producers responding	6	14	14
Average injection pressure, psig			
Before	210	240	274
After	595	650	780
Treatment size, lbm polymer	15,500	29,600	33,000
bbl water	87,000	182,000	189,000
Incremental recovery, bbl oil	115,000	130,000	33,000
bbl/acre-ft	32	16	6.5
Cost, $ thousand	37.5	135	115

streaks in the Chubbee sand and corresponding water diversion.

The polymer projects have been credited with increasing tract recovery from a 1972 project high of 32 bbl/acre-ft (4125 $m^3/km^2 \cdot m$) to a low in 1979 of 6.5 bbl/acre-ft (838 $m^3/km^2 \cdot m$). These figures correspond to 20 to 4% of the 162 bbl/acre-ft (20 881 $m^3/km^2 \cdot m$) projected unit recovery.

Producer Stimulation

Selective stimulation of producing wells has proved a successful method of improving recovery at the Hewitt Unit. Ninety-seven of the 140 active producers have cemented casing strings that permit the selective fracturing of a producing sand. The other active producing wells were drilled during primary development and have two or more uncemented liners through the pay interval, prohibiting selective stimulation. An average stimulation workover consists of six stages in four selected intervals in a producing well. The largest stimulation workover consisted of 13 stages in 10 producing intervals. A standard fracture stage consists of 5,000 gal (18.9 m^3) of emulsion-based fluid and 8,800 lbm (3992 kg) of sand.

Seventy-one stimulation jobs have been completed from 1972 to the present. Overall, the 71 stimulation jobs have yielded an average first-year gain of 64 BOPD (10.2 m^3/d oil). Thirty-five of the fracture jobs were completed by the end of 1973. Criteria for selecting zones for stimulation include: (1) individual sand quality, (2) individual flood performance in relation to other producers, (3) cumulative and current injection rates by zones in offset inputs, and (4) mechanical condition of the wellbore.

Artificial Lift Optimization and Selective Testing

Existing lift equipment does not have the capacity to pump off all the wells in the unit. Fluid levels are monitored and equipment is moved to maximize fluid production from the higher oil-cut producing sands.

Individual sands have been tested in 15 producing wells to locate watered-out zones or zones needing stimulation. Intervals are tested individually by isolation with bridge plug and packer. Producing well wireline surveys have not been used at the unit for the following reasons.

1. High water-cut production lies outside the accuracy of the tools.
2. The fluid level is below more than half of the producing zones.
3. It is difficult to run the tool past the submersible pump.

Selective testing is expensive in terms of tool rentals, well servicing, and lost production, but the results have shown it to be economical. Selective stimulation treatments of 16 producing zones in 10 wells have yielded a 450-BOPD (71.5-m^3/d) first-year buildup. Additionally, 14 uneconomical zones have been squeeze cemented or blanked off.

Drilling

In addition to the 122 wells drilled during the start of waterflood operations, nine producers and three injection replacement wells have been drilled. Seven of the producing wells were successful, one was marginal, and the ninth well gave very little buildup. Cumulative oil production as of Jan. 1, 1980, from the nine replacement wells was 2.38 MMbbl (378 390 m^3) or approximately 265,000 bbl (42 132 m^3) per well. Currently the wells produce 600 BOPD (95.4 m^3/d oil) or 67 BOPD (10.7 m^3/d oil) per well. The three injection inputs were drilled to replace wells with mechanical problems that prevented needed injection distribution. Three of the wells drilled during 1974 and 1976 resulted in an increase in producing-tract ultimate recovery. The old producing wells in these tracts were projected to recover 122 bbl/acre-ft (15 725 $m^3/km^2 \cdot m$). The three new wells resulted in an increase in projected recovery of 45 bbl/acre-ft (5800 $m^3/km^2 \cdot m$) or a total tract recovery of 167 bbl/acre-ft (21 525 $m^3/km^2 \cdot m$).

TABLE 4—MULTIPLE PRODUCING PATTERNS vs. REMAINDER OF UNIT, COMPARISON OF PATTERN RECOVERY

	Area (acres)	Number of Producing Wells	Volume (acre-ft)	Pattern Recovery	
				MMbbl	bbl/acre-ft
Producing Patterns with multiple wells	466	47	79,009	17.6	223
					Δ85
Remainder of unit	2,144	93	205,691	28.4	138
Unit total	2,610	140	284,700	46.0	162

TABLE 5—HEWITT UNIT RECOVERY

OOIP, MMbbl	350.8
Cumulative primary to unitization, MMbbl	98.5
% OOIP	28.1
Estimated unit primary from March 1, 1968, MMbbl	11.1
Unit ultimate primary, MMbbl	109.6
% OOIP	31.2
Estimated unit ultimate from March 1, 1968, MMbbl	46.0
Unit area ultimate (primary and secondary), MMbbl	144.5
% OOIP	41.2
Ultimate flood gain over ultimate primary, MMbbl	34.9
percent of ultimate primary, %	31.8

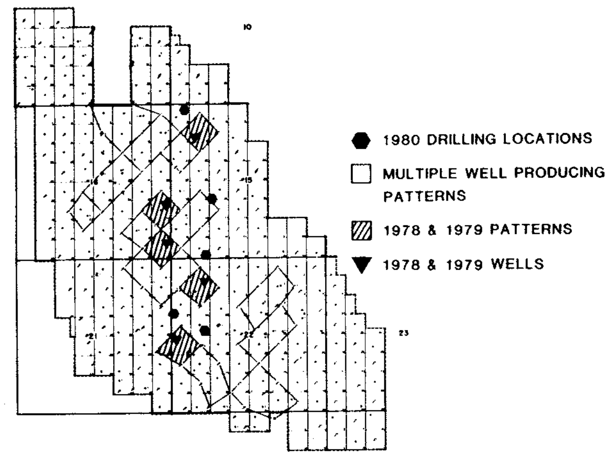

Fig. 11—Hewitt Unit infill drilling.

The results of replacement well drilling (increased ultimate tract recovery) led to a study of all producing patterns in the unit with more than one producing well. The study results (Table 4) indicated that multiwell producing patterns are predicted to average 85 bbl/acre-ft (10 956 $m^3/km^2 \cdot m$) greater recovery than single well patterns. The results of this study initially led to five infill drilling locations (Fig. 11).

The five infill wells averaged initial potential of 162 BOPD (25.8 m^3/d oil) per well. These wells should increase tract recovery by an average of 43 bbl/acre-ft (5542 $m^3/km^2 \cdot m$). The infill drilling program has continued in 1980 and 1981 with five and 24 additional wells, respectively.

Recovery

The Hewitt Unit is expected to recover 46 MMbbl (7×10^6 m^3) of oil through the life of the unit. Table 5 summarizes unit recovery, reflecting 34.9 MMbbl (5×10^6 m^3) of additional oil recovery over primary. Without the optimization work programs outlined earlier, the unit would have produced only 41 MMbbl (65×10^6 m^3) of oil. The waterflood optimizing methods therefore will yield an additional 5 MMbbl (794 936 m^3).

Conclusions

The results achieved at the Hewitt Unit waterflood demonstrate the benefits of a thorough surveillance program and the development of measures to optimize recovery. Early programs to increase recovery included triple-completion injection wells, tubing and packer installations for further injection distribution, and sand fracture treatments of producing wells. Recent techniques have included the polymer-augmented injection projects and an infill drilling program. These optimization methods have slowed production decline and increased ultimate recovery. Methods used at Hewitt should have application in other waterflood operations.

References

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SI Metric Conversion Factors

acre	× 4.046 873	E+03	=	m^2
acre-ft	× 1.233 489	E+03	=	m^3
°API	141.5/(131.5+°API)		=	g/cm^3
cp	× 1.0*	E−03	=	Pa·s
cu ft	× 2.831 685	E−02	=	m^3
in.	× 2.54*	E+01	=	mm
°F	(°F−32)/1.8		=	°C
ft	× 3.048*	E−01	=	m
lbm	× 4.535 924	E−01	=	kg

*Conversion factor is exact.

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